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IPP

INTERMOUNTAIN POWER PROJECT
A DEVELOPMENT OF INTERMOUNTAIN POWER AGENCY

July 15, 1983

Mr. Brent C. Bradford
Executive Secretary
Utah Air Conservation Committee
150 West North Temple
Salt Lake City, Utah 84110

Dear Mr. Bradford:

Intermountain Power Project (IPP)
Revised Request for Information

This is to supplement our letter to you dated June 22, 1983 which was in response to your letter of June 8, 1983 requesting additional information pertaining to issuance of a modified air quality approval order for the IPP.

The enclosed "Position Paper on Utah Review of IPP Permit" and its attachments reiterate our legal position, summarizes the factual basis for concluding that the emission limits in the original air quality approval order still represent best available control technology, explains how the proposed control equipment will assure compliance with those emission limits and responds to certain concerns that have been expressed by interested individuals.

If you or your staff require any additional information, please contact Mr. Roger T. Pelote at (213) 481-3412.

Sincerely,

James H. Anthony RP

JAMES H. ANTHONY
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Intermountain Power Project

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Intermountain Power Project

Position Paper

on the

Utah Department of Health's

Review of the IPP Construction Permit

July 18, 1983

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Attachment 2	ERT report entitled "Effects of NOx Emissions from the Proposed Inter- mountain Power Project on Deposition and Surface Water Acidifica- tion in the Wasatch and Uinta Mountains."
Attachment 3	H. E Cramer's July 1, 1983 letter to James Anthony, responding to comments by the Utah Chapter of the Sierra Club on IPP's NOx emissions.
Attachment 4	The April 1980 study by the Los Angeles Department of Water and Power entitled "Study for Particulate Control Equipment--Electrostatic Precipitators and Fabric Filters--Intermountain Power Project.
Attachment 5	The Department of Water and Power study entitled "The Specification & Design of High Availability Boilers for the Intermountain Power Project".
Attachment 6	A survey by the Utility Data Institute (UDI) concerning NOx emission limits imposed on other bituminous coal-fired power plants.
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IPP POSITION PAPER

I. Introduction

On December 3, 1980, the Utah Department of Health (DOH) issued the Intermountain Power Project (IPP) an approval order to build the four-unit, 3000 MW Intermountain Generating Station (IGS). That order included emission limits reflecting the degree of emission reduction attainable by "best available control technology" (BACT). These BACT limits were specified for sulfur dioxide (SO2), nitrogen oxides (NOx), and particulate emissions and were based upon the determination of the emission levels that could be attained by control technology which was available in 1980. IPP proceeded to make design, procurement and substantial financial commitments to meet the design objectives established by the 1980 BACT emission limits.

On June 8, 1983 -- shortly after IPP announced that IGS would be reduced from four units to two units -- the DOH requested additional information on the feasibility and costs of retrofitting alternative methods for controlling SO2 and NOx emissions at IPP's IGS. The information was requested to aid DOH in its decision to re-evaluate its 1980 BACT determinations. On July 6, 1983, IPP representatives met with DOH staff. At that meeting, possible changes in the BACT emission limits for SO2 and NOx were identifed by DOH staff.

The purpose of this memorandum is twofold. First, it reiterates IPP's legal position opposing BACT re-review for IGS. Second, it summarizes the legal, policy, and technical reasons why the current emission limits in the IPP permit represent BACT for IGS, and explains why the proposed control equipment will assure compliance with the current permit limitations.

This memorandum is supported by extensive technical analyses. In June, IPP submitted to DOH KVB's June 1983 report, entitled "Technical Evaluation of Alternative NOx Control Technologies" ("the KVB Report"), and Black & Veatch's June 1983 report entitled "Cost Analysis of Various NOx and SO2 Control Technologies for the Intermountain Power Project" (the "Black & Veatch Report"). Attached to this Position Paper are additional technical analyses and other relevant information. Attachment 1 is a supplemental KVB report entitled "Review and Evaluation of Mill Creek Unit 3 and A.B. Brown Unit 1 NOx Data" ("the Supplemental KVB Report"). Attachment 2 is an ERT report entitled "Effects of NOx Emissions from the Proposed Intermountain Power Project on Deposition and Surface Water Acidification in the Wasatch and Uinta Mountains." H. E Cramer's July 1, 1983 letter to James Anthony, responding to comments by the Utah Chapter of the Sierra Club on IPP's NOx emissions, is Attachment 3. Attachment 4 is the April 1980 study by the Los Angeles

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Department of Water and Power entitled "Study for Particulate Control Equipment--Electrostatic Precipitators and Fabric Filters--Intermountain Power Project." The Department of Water and Power study entitled "The Specification & Design of High Availability Boilers for the Intermountain Power Project" is Attachment 5. Attachment 6 is a survey by the Utility Data Institute (UDI) concerning NOx emission limits imposed on other bituminous coal-fired power plants. Attachment 7 is a July 1, 1983 memorandum from Black & Veatch concerning SO2 removal costs per ton of SO2 removed. Finally, Attachment 8 is a 1978 memorandum from EPA entitled "BACT Information for Coal-fired Power Plants."

II. IPP'S Position Concerning DOH's Current BACT Inquiry

IPP believes that it is inconsistent with the law and otherwise inappropriate for DOH to re-review the BACT limits for the IPP's Intermountain Generating Station. An administrative agency like the DOH does not have the inherent authority to reopen or reconsider a final permit or license condition *sua sponte*. It can reopen a permit only if that specific power is conferred upon the agency by the express terms of the statute creating the agency,[1/] or if a

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1/See, e.g., Pacheo v. Clark, 44 Cal. App. 2d 149, 112 P.2d 67 (1941) (absent clear intention of the legislature to vest agency with continuing jurisdiction, the Agency had no power to alter or modify its orders).

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substantial change in circumstances or fraud is shown.[2/] Moreover, to the extent that an agency's authority to modify an effective permit or license is unclear, the presumption must be that the agency does not have such authority.[3/]

The following sections summarize the facts of this case and then set out the limits of DOH's "rereview" authority under state law.

A. Summary of the Facts

The BACT limits in the IGS permit were established in the June 1980 U.S. Environmental Protection Agency (EPA) prevention of significant deterioration of air quality (PSD) permit and in the December 1980 DOH air quality approval order. The BACT limits were based upon comprehensive analyses

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2/ Cf. Clean Air Act § 307(b)(1); Oljato Chapter of Navajo Tribe v. Train, 515 F.2d 654, 662 (D.C. Cir. 1975) (new information may cast doubt on validity of order that was valid when issued); Carisso v. McGoldrick, 133 NYS2d 531 (1954) (stating that fraud is inherently a sufficient basis for review by an administrative body of its own order.); Miles v. McKinney, 174 Md. 551, 199 A. 540 (1938); Atlantic Refining Co. v. Zoning Board of Appeals, 142 Conn. 64, 111 A.2d 1 (1955); Willmont Liquors, Inc. v. Rohan, 2 Misc. 2d 768, 149 NYS2d 874 (1956) (reversal by the State Liquor Authority of its determination denying an application to transfer a license to other premises, which was merely a change of mind unsupported by new or additional evidence, without changed condition, was held to exceed the power of the administrative agency, although the reversal occurred within 8 days of the original determination).

3/ CAB v. Delta Airlines, 367 U.S. 316, 323-25 (1961).

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of the emission limits that could be attained by a source making design and procurement commitments in 1980. At the time the permits were issued, though, none of the major control equipment had been selected nor had a boiler manufacturer been chosen. The IPP permit applications indicated that the IPP preliminary design called for a lime scrubber to control SO2 emissions and an electrostatic precipitator (ESP) to control particulate matter emissions. IPP also gave the DOH and EPA preliminary design data on low NOx boilers including a maximum heat input value.

Based on the comprehensive data available concerning emission limits that could be met by a source making design and equipment commitments in 1980, the PSD permit and the state approval order imposed BACT limitations which required (1) for sulfur dioxide, a 90 percent removal and a mass emission limit of 0.15 pounds per million Btu;[4] (2) for particulate matter, a limit of 0.02 pounds per million Btu; and (3) for NOx, a limit of 0.55 pounds per million Btu on a 30-day

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[4] The state approval order established a mass emission limit of 0.155 pounds per million Btu based upon the analysis set out below. The EPA permit set a limit of 0.15 pounds per million Btu basis on rough (now outdated) emission factors. IPP has designed the IGS units to meet the more stringent limit of 0.15 pounds per million Btu.

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average.[5] All the IGS BACT emission limits are more stringent than the limits set by EPA in June of 1979 when, after an extensive rulemaking effort to determine the control capabilities of available technology and the costs of imposing such technology, EPA established new source performance standards (NSPS) for coal-fired power plants.[6]

After issuance of these EPA and DOH permits, IPP completed control equipment studies, issued bids for the major items of equipment and began the coal procurement process. After discussions with DOH, IPP made final decisions on refinements and modifications to the preliminary design of the control systems for particulate matter and SO2. Specifically, IPP decided to use a baghouse rather than an electrostatic precipitator to control

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5/The state approval order NOx BACT limit was 0.60 pounds per million Btu, the same as the applicable new source performance standards; the EPA limit was 0.55 pounds per million Btu. The IGS units will meet the 0.55 pounds per million Btu limit.

6/The applicable NSPS for the IGS are set out in 40 C.F.R. Subpart Da, §§ 60.40a-60.49(a)(1982). They were promulgated by EPA in 1979 -- shortly before the EPA and the DOH made their BACT findings for the IGS. 44 Fed. Reg. 33613. The NSPS for SO2 applicable to IGS would require it to meet a percentage reduction standard of 70 percent and would require emissions to be controlled to approximately 0.45 pounds per million Btu heat input. The applicable federal NSPS requires plants like IGS to meet a particulate matter emission standard of 0.03 pounds per million Btu. The applicable NSPS requires new power plants burning bituminous coal (like that burned at IGS) to meet a NOx emission limit of 0.6 pounds per million Btu on a 30-day average.

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particulate matter and to use a limestone scrubber rather than a lime scrubber to meet the BACT limit for SO2. These changes were made in order to provide more reliable and cost-effective compliance with the BACT emission limits in the IGS permits. IPP also selected Babcock & Wilcox as its boiler manufacturer; the final boiler specifications given by Babcock & Wilcox provided for each boiler to have a heat rate that is slightly higher than the one used in the preliminary design.

In contracting for and installing all pollution controls at IGS, IPP relied on the 1980 permitted emission limits; IPP negotiated and received guarantees from control equipment vendors -- guarantees specifically designed to assure that IPP will meet the 1980 stringent BACT limits for all three pollutants. Hundreds of millions of dollars have already been expended to design and construct IGS in order to meet the 1980 pollution control design objectives; on-site construction of both units is well underway. As a result of these irrevocable economic and physical commitments to the 1980 IGS design requirements for control equipment, any significant changes now in the design objectives for major items of equipment or any changes which affect the physical layout of structures or equipment will disrupt construction and can substantially delay completion of the project at tremendous cost.

B. The DOH Does Not Have the Authority to Change the BACT Limits in this Case

The DOH does not have the authority to change the BACT limits in the IGS permit. The Utah Code contains no general provisions expressly allowing the DOH to reopen the BACT terms of its approval orders sua sponte, and the DOH Air Conservation Regulations do not give the DOH blanket authority to reopen approval orders.

The DOH rules on approval orders authorize the DOH to require a source owner to apply for an approval order, and for DOH to issue such an order, only when an owner is (1) planning to construct a new installation; (2) making modifications to an existing installation which modifications will increase the amount or change the effect of, or the character of, air contaminants discharged; or (3) planning to install an air cleaning device or other equipment intended to control emission of air contaminants from a stationary source. Utah DOH Regulation 3.1.1. The first two conditions do no apply in this case, and, as explained below, even if the third condition is applicable, the review is limited to a determination of compliance with the 1980 permit limits.

First, and most important, IPP is not proposing to construct any new installation. IPP has not made any changes in the project which, by any reasonable standard, could be considered to be of the magnitude to constitute the construction of a new installation. As discussed above, the design of the project has matured and, as is true of any major project, differences between preliminary and final design have emerged. Such differences are to be expected, particularly where, as here, very rigorous design objectives are established in the construction permit for the source.7/

A 1978 EPA memorandum, interpreting the BACT regulations which are now being implemented by DOH, explicitly recognizes that differences between preliminary and final design of the kind involved in this case are to be expected and that they do not constitute a significant change in the project and thus do not trigger new permitting requirements and reevaluation of BACT limits. As this EPA memorandum explains, when utilities apply for new source permits, they often submit only preliminary design information as a basis for setting BACT limits and then agree to submit final detailed engineering design specifications prior to construction of the control equipment. This was the case with IGS. The memorandum then recognizes that the final engineering design and vendor specifications will often vary from the preliminary information. This also was the case here. These variations, EPA observes in terms that parallel the facts here, may "<u>include basic changes in equipment design</u>

7/As noted above, EPA's 1979 NSPS determinations on achievable control levels were virtually contemporaneous with the BACT determinations for IPP. Nevertheless, IPP's BACT limits were in each instance more stringent than the federal NSPS.

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such as a shift from an ESP to a baghouse, a change from a lime/limestone scrubber to a regenerable scrubbing system or a change in the design approach to ensuring reliability." (Emphasis added.)

The EPA memorandum goes on to explain that, when there are such variations in final design specifications, the utility must show only one thing -- that the equipment meeting the final specifications is equivalent in performance and reliability to that covered in the initial BACT demonstration. As a result, the authority reviewing the final design information is to "seek only those data elements which are necessary to support an engineering judgment that the proposed system will perform reliably at the specified emission rates." Since the submission of the final engineering design specifications is required, as it is here, EPA then concludes that the submission of such design specifications, "would not constitute a reopening of the permit process, and [would not trigger] the need for an opportunity for public comment on this material."8/

In sum, the differences between the preliminary and final design of the IPP control equipment cannot be said to

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8/EPA memorandum on "BACT Information for Coal-Fired Power Plants," sent from Walter C. Barber to the EPA Regional Offices (December 22, 1978). A copy of this memorandum is Attachment 8 of this Position Paper.

re-open the permit process on the ground that IPP is constructing a new installation that was not previously permitted.

Nor can the refinements in design of the boiler be said to constitute a "modification" of an existing source, triggering new BACT review. Under Utah law, there is no modification unless there is a potential increase in emissions from a "source." Utah DOH Regulation 1.1.77. Under the definition of "source" in the Utah Air Conservation Regulations, IGS is one source.[9/] Thus, it is an increase in total emissions at the IGS which would constitute a modification under Utah law. If IGS increases emissions at individual emission units within the project and offsets those increases by decreases at other project emission units, IGS would not be considered a modified source.

IPP is not proposing to increase emissions at IGS. While the boilers will have a slightly higher heat rate than originally anticipated and therefore may produce more NOx

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9/Under the Utah DOH Regulation 1.1.111, a "source" means "any structure, building, facility, equipment, installation or operation (or combination thereof) which emits . . . any air pollutant and which is located on one or more contiguous or adjacent properties and which is owned by the same person . . . ." Intermountain Generating Station -- including the boilers and associated control equipment -- is all on the piece of property and is under common ownership and thus constitutes one "source" under Utah law.

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emissions on a per unit basis than would be produced if there were a lower maximum heat rate, total emisions from the source will be significantly less than described in the original application for an approval order for IGS. On March 31, 1983, the size of the project was officially reduced from four to two generating units, cutting potential emissions from the source almost in half.

In sum, it is a net increase in emissions at the "source" (which in this case is a multi-unit generating station) that triggers the modification requirements of the DOH regulations. The total emissions at the IGS "source" are, as a result of the changes between preliminary and final design, almost one-half of the emissions permitted in 1980.

Finally, there is the issue of whether the DOH has approval order review authority because IPP is planning to install different air cleaning devices -- i.e the baghouse and limestone scrubber -- than were originally proposed. For the reasons stated in the 1978 EPA memorandum discussed above, these devices should not be viewed as triggering a new BACT review since the differences between preliminary and final design, such as those in this case, are to be expected. Nevertheless, even if a new approval order for the IGS baghouse and limestone scrubber system is required, the agency is not authorized to rewrite BACT terms in connection with issuance of that approval order.

Under Utah DOH Regulation 3.1.8, the Executive Secretary is required to issue an approval order if he determines that the control devices are at least BACT and that their installation will be in accord with applicable state and federal rules. As noted above and as described in much greater detail below, the IGS baghouse and limestone scrubber will control emissions at least to the level of BACT; the baghouse will achieve an emission rate of 0.02 pounds per million Btu and the limestone scrubber will achieve an emission limit of 0.15 pounds per million Btu, which is actually lower than the BACT limit set in the DOH approval order. Also, the installation will be in accord with applicable state and federal air quality requirements. Thus, under the terms of the DOH rules, the Executive Secretary is not authorized to revise the BACT limits in connection with his review of the final design of the IGS SO2 and particulate matter control systems.

C. Summary

In sum, IPP received a permit to construct a facility with control equipment that would be designed to assure compliance with the emission limits contained in the December 3, 1980 approval order. IPP is constructing such a facility. IPP recognizes the appropriateness of state review to determine whether the final design of the control equipment will in fact assure compliance with the 1980 BACT limits. Where, as here, there is no net increase in facility emissions as a result of

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changes in design, there is no basis in Utah law for establishing new BACT limits that differ from those previously established.

III. The Current Emission Limits Constitute BACT

Although IPP believes that it is inappropriate to conduct a BACT re-review for a project that, in good faith, has made commitments to equipment that will assure compliance with the BACT limits that were properly set at the time of permitting, IPP has prepared data which demonstrate that the current permit limits represent BACT for the IGS. The following sections summarize the legal framework for a BACT review and then apply that framework to the facts in this case.

A. What Is BACT?

Federal law and the Utah Air Conservation Act call for the application of BACT for reduction of certain regulated pollutants -- in this case, SO2, NOx, and particulate matter. Under Clean Air Act section 169[10/] and Utah DOH Regulation 1.1.23, BACT for a pollutant means an emission limit for that pollutant reflecting the maximum degree of reduction that is achievable taking into account energy, environmental, economic and other impacts. Each BACT determination is to be made on a

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10/ 42 U.S.C. § 7469(3)

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case-by-case basis, although the application of BACT may not result in pollutant emissions in excess of applicable emission levels established pursuant to Clean Air Act section 111.

Federal and state law thus ask the permit issuer, in setting BACT limits, to consider on a case-by-case basis what is achievable, environmentally sound, and cost-effective. A significant body of federal case law explains what is meant by the term "achievable" and how energy, environmental, and economic costs are to be taken into account on a case-by-case basis. In the context of this case, DOH may rely upon the record supporting the 1980 BACT determinations in deciding not to change those limits. On the other hand, if the BACT limits were changed, DOH would have to demonstrate that it considered relevant factors and disclosed and explained fully the basis for its change of course. If the record does not contain such an explanation or if the facts do not support the DOH conclusions, a court would conclude that the new limits are arbitrary and capricious.[11] The following discussion explores the burdens DOH must bear in order to support any more stringent BACT limitations.

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[11]Motor Vehicles Mfrs. Ass'n. v. State Farm Mutual Ins. Co., 51 U.S.L.W. 4953, 4955 (U.S. June 24, 1983) (No. 82-354) ("an agency changing its course. . . is obligated to supply a reasoned analysis for the change beyond that which may be required when an agency does not act in the first instance").

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1. Demonstrating Achievability

On the matter of "achievability," the case law makes it clear that when a decisionmaker projects that a certain emission limit is achievable, his decision must meet the following criteria:

(1) The decision must specify the precise data and assumptions on which the decisionmaker's projections are based and establish the reasonableness and reliability of the methodology.[12] The decision may not rely on "crystal ball" inquiry or extrapolate from "purely theoretical or experimental" technology.[13]

(2) Where the decision is based on a projection that an as-yet-undemonstrated technology will work in the future, that projection must be able to withstand close scrutiny. There may be room for a projection that a certain technology will eventually be adequate to achieve a particular emission reduction if that technology is to be installed by sources several years in the future; however, if a standard is set based on a technology that is to be installed immediately, then "the latitude [given to the] projection is correspondingly narrowed."[14]

(3) If the BACT decision is based on data from a test facility, the analysis supporting the

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12/Portland Cement Ass'n v. Ruckelshaus, 486 F.2d 375, 391-93 (D.C. Cir. 1973); International Harvester Co. v. Ruckelshaus, 478 F.2d 615, 642-43, 647-48 (D.C. Cir. 1973).

13/Portland Cement, 486 F.2d at 391-92.

14/Id. at 391-92. Since IGS is under construction and any change in design must be implemented immediately, there is little or no latitude for projection.

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decision must consider the possible impact on emissions due to recognized variations in operation when the technology is applied in full-scale, commercial practice and must offer some rationale for the achievability of the standard in light of those variations.[15] The conditions under which tests are conducted for purposes of standard development should be similar to the conditions specified for enforcement.[16] Thus, for example, the court carefully scrutinized an Agency conclusion that a technology would work at full load operation when the facilities being tested were operating only at approximately 52% of capacity.[17]

In short, in making a BACT determination a decisionmaker can hold a source to a standard of improved design and operational advances only where (1) there is "substantial evidence that such improvements are feasible and will produce the improved performance necessary to meet the standard,"[18] and (2) the decisionmaker sets out that substantial evidence

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15/National Lime Ass'n v. EPA, 627 F.2d 416, 434-43 (D.C. Cir. 1980).

16/Portland Cement, 486 F.2d at 396.

17/Essex Chemical, 486 F.2d at 436.

18/Sierra Club v. Costle, 657 F.2d 298, 364 (D.C. Cir. 1981); Bethlehem Steel v. EPA, 651 F.2d 861, 876 (3d Cir. 1981). IGS, of course, is no longer a "new source." Construction is underway and substantial commitments have been made to meet the 1980 design objectives established by the DOH and EPA. In this setting, changes in design are much less feasible and improvements in performance much less certain than in the case of standards set for new sources that will be designed and constructed after establishment of the standards.

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clearly and precisely for the record.[19/] In sum, the burden is on DOH to establish the technical basis for any determination that a particular emission limitation is achievable.

2. Demonstrating that a BACT Limit is Cost-Effective

Finding that a particular technology is demonstrated and that a specific emission level is achievable represents only the starting point for a BACT determination. Each achievable level of control must be evaluated in light of its economic costs, energy requirements and environmental implications. The level of control representing "best" technology must therefore reflect a balancing of factors, including the costs associated with achieving emissions reductions. A control technology will be "best" technology only if it is a cost-effective control technology and reflects a balancing of the statutory factors. When technology is being applied in a "retrofit" context, -- i.e., when the technology is not part of the original design and thus its installation requires changes to be made to the original design -- then cost considerations may justify substantially less stringent limitations than would be

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19/ Portland Cement, 486 F.2d at 391-92.

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appropriate for a new facility.[20]

3. Making a Case-by-Case Determination

Finally, the law emphasizes the need to make each BACT determination on a case-by-case basis. In determining appropriate emission levels, the decisionmaker must keep in mind that BACT emission levels may be no less stringent than the levels established by applicable new source performance standards (NSPS) set under Clean Air Act section 111, but that the BACT levels are indeed set case-by-case taking into account the characteristics of the specific source.[21] As a result, what may be applicable to most plants, may not be appropriate

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[20]Cf. ASARCO Inc. v. EPA, 578 F.2d 319, 330-31 (D.C. Cir. 1978) (Leventhal, J., concurring) (in setting new source performance standards, the EPA Administrator may set less stringent standards for modified sources -- *e.g.*, retrofit sources -- than for new sources since such distinctions may be "warranted by cost differences and cost-benefits analysis"). The visibility protection provisions of the Clean Air Act reflect the importance of balancing all relevent factors in a retrofit situation to avoid the imposition of improper control requirements. Under § 169(g)(2) of the Act, when the states specify "best available retrofit technology" ("BART") for sources impairing visibility in class I areas, emission limits are to be based on the consideration of the cost, affordability, adverse side effects, and efficiency of alternative control options. Section 169A(g)(2). EPA's BART regulations expressly acknowledge that the "best" technology is not necessarily the one that removes the most pollution. EPA, Guidelines for Determine Best Available Retrofit Technology for Coal-Fired Power Plants and Other Existing Stationary Facilities," EPA-450/3-80-0096 and pages 20-21 (Nov. 1980)(incorporated by reference into 40 CFR §§ 51.300-307 (1982)).

[21]Northern Plains Resource Council v. EPA, 645 F.2d 1349, 1358-62 (9th Cir. 1981.)

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for a particular facility[22/] -- e.g., as in the case of IGS where, if any new technology is required, it would not be part of the original plant design and therefore would be a retrofit. Specifically, if adding a new technology would involve a great deal of additional expense to reduce already well controlled emissions, the new technology should be rejected as BACT.[23/]

B. Application of the BACT Criteria to IGS

If we apply the BACT standards to the facts of the IPP case, it is clear that the current emission limits represent BACT. The following subsections summarize the BACT data submitted by IPP and apply the BACT standards to those data.

1. The Current SO2 Emission Limits Represent BACT

a. The Permitted SO2 Limits

IPP must achieve a 90 percent reduction of SO2 emissions, and must meet a mass emission standard of 0.15 pounds of SO2 per million Btu heat input.[24/] Compliance

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22/ Id. at 1359 n.29.

23/ Cf. Northern Plains, 645 F.2d at 1361.

24/ As noted above, the federal new source performance standards for SO2 applicable to IGS would require it to meet a percentage reduction standard of 70 percent and would require emissions to be controlled to approximately 0.45 pounds per million Btu heat input. The permitted SO2 limits for the IGS units are thus significantly more stringent than the federal NSPS.

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with these requirements will be determined using continuous monitors and 30-day rolling averages.[25]

The extremely stringent percent removal standard goes well beyond the federal NSPS standard of 70 percent. In 1979, EPA determined that that level reflected the most cost effective technological standard for low sulfur coals. The 90 percent removal standard imposed in its permit requires IPP to design a system which approaches the limits of the demonstrated removal capabilities of SO2 scrubbers. To meet this condition, IPP contracted to purchase and build a state-of-the-art limestone scrubber. This scrubber has been carefully designed so that it can comply with the standard while burning all of the various Utah coals planned for use at IGS.

The mass emission limit of 0.15 pounds of SO2 per million Btu is also one of the most stringent in the country. The mass emission limit was set based upon information estimating the sulfur content of the coals to be burned at IGS and then assuming that 90 percent of the SO2 would be removed by the scrubbers. The mass emission limit for SO2 is thus based in large part on the sulfur content of the coal to be burned.

25/The state approval order established a mass emission limit of 0.155 pounds per million Btu based on the analysis set out below. The EPA permit sets a limit of 0.15 pounds per million Btu based on rough (now outdated) emission factors in AP-42. IPP has designed IGS to meet the more stringent limit of 0.150 pounds per million Btu.

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In its PSD permit application, IPP discussed the sulfur content of the coal it would burn at IGS and used estimates of coal characteristics. Estimates, rather than actual data, were required because IGS is not a mine-mouth plant and thus, at the time of permitting, it was not clear what coal would be burned. IPP based its coal quality information on core hole sample data from existing mines and leases located in the Northern Wasatch Plateau and the Book Cliffs coalfields. Adjusting that core hole data to reflect worst case conditions, IPP estimated that it would be getting coal with an average Btu content of 10,200 and average sulfur content of 0.79 percent. The DOH SO2 mass emission limit was set based on those coal quality estimates and on the assumption of 90 percent SO2 reduction through a scrubber. IPP accepted the permit conditions based on these estimates and this assumption.

Having once accepted that mass emission limit, IPP then took steps to assure that the coal purchased would comply with the limit. To accomplish this, IPP's coal contracts all include guarantees for coal qualities that the purchased Utah coal must meet. The contracts provide a range of sulfur in the coal and a typical sulfur content. As a result of normal sulfur variability in coal, some of the coal is likely to be higher in sulfur content than 0.79 percent; some is likely to be lower. IPP is aware of this, and the scrubber system has

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been designed so that the SO2 emissions from the coal -- after scrubbing -- will meet the permitted mass emission limit of 0.15 pounds per million Btu on a 30-day rolling average basis.

In summary, the IGS SO2 emission control system has been very carefully designed to ensure that 90 percent SO2 reduction can be achieved on a 30-day average and that the total mass SO2 emission limit of 0.15 pounds per million Btu can be met using the Utah coal which IPP is required to burn at IGS and which IPP has contracted to purchase.

b. Obstacles to Achieving More Stringent SO2 Limits

Although the IGS scrubbers have been designed to reduce SO2 emissions by 90 percent during the 35-year life of the plant, the DOH's June 8, 1983 letter asks IPP to evaluate the cost of a "95% SO2 scrubber." In addition, at a July 6, 1983 meeting, DOH representatives asked IPP to evaluate the possibility of IGS' meeting a mass emission limit of 0.14 pounds per million Btu. The following discussion summarizes problems associated with making any changes to the 90 percent standard or the 0.15 mass emission limit.

(1) The 90 Percent Standard

There are serious obstacles to achieving a 30-day average 95 percent reduction rate over the entire 35 year lifetime of a power plant. As stated by Black & Veatch in its report, "Cost Analysis of Various NOx and SO2 Control

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Technologies for the Intermountain Power Project," which was submitted to DOH on June 22, 1983, 90 percent SO2 removal on a 30-day average basis is the upper limit which limestone scrubbers have been demonstrated to achieve. Although wet limestone scrubbers are capable of achieving SO2 reductions in excess of 90 percent for short durations, extended operation in excess of 90 percent has not been demonstrated at any operating facility. The Black & Veatch Report explains that the major obstacle which prevents a scrubbing system from continuously achieving SO2 removal efficiencies in excess of 90 percent is the system's inability to catch up for periods of reduced SO2 removal rates caused by such factors as inherent system variability, component failures, and system chemistry upsets.

For instance, if a scrubbing system designed for 90 percent SO2 removal achieved only 70 percent removal for 10 hours due to a component failure, it would then have to be operated at 95 percent removal for 40 hours in order to average 90 percent removal over a 30-day period. However, if a scrubbing system designed for 95 percent SO2 removal experiences a component failure which causes it to operate at 70 percent removal for 10 hours, it will require that the system be operated for 125 hours at 97 percent SO2 removal to achieve an average SO2 removal of 95 percent. Should multiple component failures occur in a 30-day period, then it may be impossible for the scrubbing system to achieve an average of 95

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percent design SO2 removal even if it could be operated at 100 percent SO2 removal.

In sum, extended operation at 95 percent SO2 removal has not been demonstrated in practice. However, even if such a limit were achievable, it would not be BACT unless it could be achieved in a cost-effective manner. Thus, the limit must be evaluated in light of its economic costs, energy impacts, and environmental implications.

The Black & Veatch Report evaluates the costs of a scrubber system designed for 95 percent reduction. If IPP were to retrofit IGS with such a 95 percent design SO2 removal system before the start of commercial operation, the Black & Veatch Report estimates that the additional capital costs, operating costs, and delay costs associated with retrofitting such a system would be $998 million (in 1986 dollars); the additional cost would be $1.118 billion (in 1986 dollars) for retrofitting the 95 percent design SO2 system after one year of commercial operation.[26/]

26/Costs for implementing a 95 percent design SO2 removal system contained in this study are based on more detailed engineering analyses, more refined estimates of replacement power costs and other costs of delay, and a more sophisticated technique for projecting capital costs than those used in earlier analyses. As a result, these estimates are more accurate than, and supercede, those contained in the Black & Veatch memorandum to Intermountain Power Project dated April 13, 1983.

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The report explains that those costs were estimated based on the assumption that, for a scrubbing system to achieve an average SO2 removal rate of 95 percent, enough redundancy must be available to dampen normal scrubber operational variability and to eliminate all avoidable outage time. The Black & Veatch Report concludes that the only way to approach this undemonstrated removal level is to install an extensive number of spare components -- for example, four additional absorber modules and an additional spray level for each absorber module. Also, there would have to be changes made in the current scrubber design to accommodate the additional equipment. The cost estimates also took into account the fact that if a decision is made to retrofit a 95 percent design SO2 removal system on July 1, 1983, then a project delay of 18 months is expected. A decision to implement a retrofit of a 95 percent design SO2 removal system following one year of operation would also require a unit outage of approximately 18 months. All these factors contribute to the approximately $1 billion scrubber retrofit costs.

An examination of the cost per ton of SO2 removed dramatically demonstrates that the incremental cost of designing a "95 percent scrubber" is not justified. Black & Veatch has estimated, for the 90 percent scrubber, that for each unit it will remove 23,200 tons of SO2 annually at an average cost of $1,260 per ton of SO2 removed. However, if a 95 percent scrubber is installed and if it is able to achieve 95 percent removal, it would only remove an additional 1,300 tons of SO2 annually at each unit. The cost to remove this additional 2,600 tons would be $50,600 per ton. This is an exorbitant price to pay for slightly lower SO2 emissions. In setting a revised NSPS in 1979, for example, EPA rejected proposals that would have cost in the range of about $2,000 to $2,500 per ton.[27]

There is also an energy penalty associated with operating a 95% scrubber. Operating a 90 percent scrubber will consume 3 to 5 percent of the total plant electrical output. Operating a 95 percent scrubber will nearly double the energy consumed by the scrubber equipment, and will add $63.5 million to costs of operating the scrubber.

In summary, evidence submitted by IPP shows that removal of greater than 90 percent of SO2 emissions on a continuous basis for the life of IGS has not been demonstrated to be achievable. Moreover, to purchase, install, and operate a scrubbing system designed to approach 95 percent removal (whether it is retrofitted now or after commercial operation) would cost approximately $1 billion, and over $50,000 for each

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27/45 Fed. Reg. 8219, Table 3 (1980); 44 Fed. Reg. 33607, 33609, Table 5 (1979). The costs reported in the text are July 1, 1986 costs; they have been scaled up from the 1978 costs used by EPA when issuing the revised NSPS.

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additional ton of SO_2 removed. Under the statutory and regulatory criteria to be followed in setting BACT, therefore, the 90 percent SO_2 removal requirement is BACT; no more stringent standard is supported by the facts.

2. Obstacles To Achieving a Standard More Stringent than 0.15 Pounds Per Million Btu

The mass emission limit of 0.15 pounds per million Btu also represents BACT. As noted above, that number was based on the assumption that IPP would burn a variety of Utah coals and reflected coal quality data from the most likely sources of Utah coal. Since the time that the SO_2 limit was set, IPP has entered into four coal contracts. Those contracts specify characteristics that all delivered coal must meet. The contract terms assure that IPP will be able to meet the 0.15 mass emission limit but do not ensure compliance with any more stringent limit. Specifically, the four existing coal supply contracts limit sulfur content to an average "worst case" sulfur limit of 0.733 pounds of sulfur per million Btu, which corresponds to an SO_2 emission rate of 0.147 pounds per million Btu when the scrubber operates at 90% removal efficiency.[28/] Economic penalties will apply to any coal supplier that does not

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[28/] One of the four contracts limits coal to a sulfur content of 0.760 pounds per million Btu, corresponding to an SO_2 emission rate of 0.152 pounds per million Btu if the highest conforming sulfur content coal were burned. Over the permitted 30-day averaging period, however, lower sulfur coal would be burned, assuring compliance with the 0.15 limit.

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conform to the contractual sulfur content limits.

In the immediate future, coal suppliers will not only be delivering marginally complying coal, but also will be delivering lower sulfur content coal so that the plant will often be achieving an emission rate lower than 0.15. However, over the life of the plant, taking into account future SO2 emission regulatory requirements, there is likely to be an increased demand and a higher price for lower sulfur coals. Thus, it is likely that, during the life of the IGS units, all Utah coal suppliers will have an economic incentive to deliver only marginally conforming coals under existing contracts. If this happens, it could become impossible for the IGS units to comply with an SO2 emission limit below 0.15 unless new contracts for lower sulfur coal could be negotiated. Since the annual fuel cost for the IGS units is estimated to be well over $100 million, the additional cost to the IPP for negotiating new lower sulfur coal supply contracts for the life of the IGS units could easily be several hundred million dollars.

Also, the imposition of a lower emission limit would shift liability for compliance from the SO2 scrubber manufacturer and coal suppliers to the IPP. This new risk could result in higher bonding interest rates and substantially higher financing costs. Since the Project has a remaining bonding requirement of approximately $3.4 billion, an increase of one percent in the bonding rate would result in an additional cost of over $100 million.

Although the costs of lowering the SO2 emission limit from 0.15 to 0.14 are very high, the benefits associated with such a permit change are minimal. To meet the current SO2 limit of 0.15, IPP will be removing approximately 46,000 tons of SO2 annually; shifting coals to achieve the marginally lower emission rate of 0.14 would further reduce annual SO2 emissions by no more than 340 tons. In fact, the actual annual reduction is likely to be far less, since IPP would, at most, be changing only a portion of its coal supplies to meet the 0.14 limit, and since the annual average sulfur content of coal delivered under renegotiated contracts may not be reduced significantly.

The SO2 ambient air quality standards and PSD increments are thoroughly protected with the current 0.15 limit. For example, the maximum 3-hour predicted IGS impact is 80 ug/m^3, which is less than 20 percent of the applicable PSD increment; when plant impact is added to the 3-hour background concentration of 26 ug/m^3, the maximum 3-hour ambient concentration is 106 ug/m^3, which is still less than 10 percent of the 3-hour secondary standard of 1300 ug/m^3. The IGS maximum 24 hour impact (32 ug/m^3) and the annual impact from the plant (1 ug/m^3) are also well below the applicable ambients standards and PSD increments.

If the IGS limit for SO2 were lowered to 0.14, that would not significantly reduce the maximum SO2 concentrations from the plant. Specifically, the maximum 3-hour SO2 plant impact would be reduced by less than 6 ug/m^3, the maximum 24-hour plant impact would be reduced by less than 2.5 ug/m^3, and the annual plant impact would be reduced by less than .1 ug/m^3. These reductions are all insignificant under criteria established by EPA,[29/] and are probably undetectable by air quality monitors. Thus, the virtually nonexistent air quality benefits of lowering the SO2 emission limit to 0.14 clearly do not justify what may be extremely high costs.

Not only are the air quality benefits negligible, but such a condition might run counter to more important air quality objectives of the state. For example, if IPP were required to meet the 0.14 limit, it would, as noted above, probably have to shift to using other, lower sulfur coals. This could result in Utah's lowest sulfur coal reserves being consumed at the remote and highly controlled (90% removal) IPP instead of at the uncontrolled and less effectively controlled emission sources that are proximate to Utah's population centers.

29/ *See* 43 Fed. Reg. 26398 (1978), where EPA stated that the minimum amount of ambient impact that EPA would consider significant for SO2 would be 25 ug/m^3 for the 3-hour averaging time, 5 ug/m^3 for the 24-hour averaging period, and 1 ug/m^3 annually.

Finally, in response to the DOH suggestion that IPP can meet the 0.14 limit because other utilities have accepted limits lower than 0.14 pounds per million Btu, it must be noted that limits lower than 0.14 have been accepted only in cases where the affected utilities have been virtually certain that they will, over the life of the affected units, be able consistently to acquire coal with a lower sulfur content than that now under contract to IPP. For example, a mine-mouth unit or other unit that is getting virtually all its coal from one source of very low sulfur coal may be able to meet an emission limit lower than 0.15 pounds per million Btu. We understand that this is the case for Utah Power & Light's Hunter Units 3 and 4, which are mine-mouth units.30/ Very low limits may also be achievable where new units are being built at a site where there are already other units subject to less stringent SO2 limits. At such sites, delivered coal with the lowest sulfur content can be burned at the new unit with the lowest SO2 limit; any higher sulfur content coal can be burned at the other units at the site. Thus, on a

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30/It should also be noted that Brigham Young University and Kennecott Corporation each get most of their coal from a single source. The small Brigham Young University boiler uses only one source of low sulfur coal, and the Kennecott Corporation facility gets at least two thirds of its coal from one source of very low sulfur coal.

case-by-case basis it may be appropriate to require these types of sources to meet emission limits lower than 0.15 pounds per million Btu. Since the same circumstances do not apply at the IGS units, it is not appropriate to reduce the SO2 mass emission limit below 0.15.

In summary changing the 0.15 pounds per million Btu mass is unjustified. It would be extremely costly and disruptive, would yield no significant environmental advantages, and would not take into account the coal contract situation at the IGS units. Thus, under the current statutory criteria for setting BACT, the current limit is BACT and should not be changed.

3. The Current Particulate Matter Emission Limit Represents BACT

The applicable federal NSPS requires plants like IGS to meet a particulate standard of 0.03 pounds per million Btu. As with the limits on SO2, the permitted particulate matter emission standard for the IGS units is more stringent than the federal NSPS. Indeed, the IGS limit of 0.02 pounds per million Btu is one of the most stringent particulate matter emission standards set for any power plant in this country and reflects the maximum degree of particulate matter reduction that can be achieved at the IGS units.

Before contracting for the purchase of particulate control equipment to meet that stringent limit, IPP studied the capabilities and costs of both electrostatic precipitators and baghouses. An April 1980 analysis conducted for IPP, entitled "Study for Particulate Control Equipment -- Electrostatic Precipitators and Fabric Filters -- Intermountain Power Project" (Attachment 4), examined both particulate collection devices and concluded that baghouses were preferable for IGS for several reasons. First, precipitator design is closely tied to coal, ash and flue gas properties; where several coals are to be burned (as is the case at IGS), designing a precipitator is difficult and expensive. If, some time during the 35 year operating life of the plant, different quality coals have to be burned, the precipitator might not be able to meet the permitted emission limit. Baghouses, however, are less affected by variations in coal, ash, or flue gas properties. The report also concluded that opacity is better controlled by baghouses, that fine particulates are better controlled by baghouses, and that a baghouse is often easier to maintain online than is a precipitator. Finally, the report concluded that it would be more cost effective to install a baghouse than a precipitator at IGS.

IPP discussed the choice of baghouse with DOH representatives and met with DOH representatives on February 5, 1981 to explain in greater detail IPP's decision to purchase a baghouse. The system that has been purchased is consistent with that previously discussed with DOH. It is one of the most advanced baghouse systems available; the manufacturer has guaranteed that the baghouse system will limit the total particulate emission rate of not more than 0.02 pounds per million Btu heat input. In sum, the current particulate limit represents BACT and the IGS baghouse can achieve compliance with that limit.

4. <u>The Current NOx Emission Limit Represents BACT</u>

a. <u>Achieving the BACT Limit</u>

The applicable federal NSPS requires new power plants burning bituminous coal (<u>i.e.</u>, the coal to be burned at IGS) to meet a NOx emission limit of 0.6 pounds per million Btu on a 30-day average. Based on the federal NSPS (which had been revised just a short time before the permitting of IGS), the Utah DOH set a 0.6 pounds per million Btu NOx emission limit in its December 1980 approval order. However, under the terms of its federal PSD permit, IPP is required to meet a NOx emission limit of 0.55 pounds per million Btu on a 30-day average. According to a survey conducted by the Utility Data Institute (see Attachment 6), no more stringent NOx emission limit has been imposed on any power plant burning bituminous coal.

In setting the 0.55 NOx limit, EPA's technical experts indicated that this represented the most stringent limitation that could be justified by available data. Letter from J. Burchard, Director, U.S. EPA IEAL, to R. L. Duprey, Director, U.S. EPA Air and Hazardous Waste Division, April 21, 1980. There are plants that have agreed to meet more stringent NOx emission limits, but those plants are burning subbituminous coal, which is less likely to cause corrosion, slagging and fouling. In setting the NSPS for power plants, EPA recognized that it was appropriate to set lower limits for users of subbituminous coals.

As described in KVB's report, "Technical Evaluation of Alternative NOx Control Technologies," IPP has contracted for the purchase of a boiler that is designed and guaranteed by its manufacturer to achieve the 0.55 pounds per million Btu, 30-day average NOx emission limit. The boiler selected by IPP is one of the most advanced second generation NSPS boilers available to the utility industry. The boilers for IPP Units 1 and 2 are Babcock & Wilcox (B&W) natural circulation, balanced draft, single reheat boilers, described in the KVB report. The boilers incorporate a burner system designed by B&W to operate at low levels of NOx without creating adverse side effects. The system incorporates a compartmented windbox for precise control of the combustion air and a low-NOx burner design developed by B&W. The B&W dual register burner provides the control of stoichiometry and the mixing of fuel and air necessary to achieve extremely low levels of NOx emissions. The windbox and burner combination is one of the most advanced systems in the industry and has been used on a large number of new second-generation boilers designed to comply with the revised NSPS for both subbituminous and bituminous coals. This system has the most demonstrated experience of the new low-NOx designs.

IPP has also gone to great lengths to maximize the availability and reliability of these units. A separate report entitled, "The Specification and Design of High Availability Boilers for the Intermountain Power Project" describes in detail the considerations that went into the selection of the boilers and their auxiliaries. The boiler was designed to fire Utah bituminous coals having a wide variety of properties. These coals have slagging and fouling tendencies which range from high to medium slagging and from low to medium fouling. The integrated burner and boiler design was selected taking these conditions into consideration. The experience of other utilities with the B&W integrated boiler and burner design will not only ensure high reliability and availability, it also ensures the highest probability of compliance with the NOx emission regulation of 0.55 pounds per million Btu imposed by the EPA PSD review.

b. Obstacles to Achieving a Lower NOx Emission Rate

The DOH, in its June 8, 1983 letter, asked the IPP to investigate five additional NOx reduction techniques: Selective Catalytic Reduction (SCR), Thermal DeNox, Overfire

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Air Ports, Lower Excess Combustion Air, and Decreased Plan Heat Releases Through Boiler Derating.

In addition, at a July 6, 1983 meeting, DOH representatives suggested that IPP investigate the possibility of meeting a NOx limit of 0.50 pounds per million Btu with the current boiler design. As a part of this evaluation, DOH asked IPP to review data from two operating plants (the Mill Creek Plant and A.B. Brown Plant), plants which the DOH identified as meeting emission limits lower than 0.55 pounds per million Btu. The KVB Report and a Black & Veatch Report on the cost of NOx controls evaluate the first five NOx reduction techniques. (These two reports were submitted to the DOH in June.) The Supplemental KVB Report, entitled "Review and Evaluation of Mill Creek Unit 3 and A.B. Brown Unit 1 NOx Data" (Attachment 1 hereto), evaluates the NOx emission levels at the Mill Creek and A.B. Brown plants and the achievability of a 0.50 NOx standard with the current boiler design.

The first KVB Report demonstrates that the NOx technologies about which DOH inquired either are not demonstrated or will not ensure further emission reductions for a plant like IGS. Specifically, the KVB Report concludes that:

1. The SCR process has not been demonstrated to be effective on commercial power plants either in systems using a baghouse, or on coals containing the catalyst poisons sodium, potassium, and calcium in the quantities present in Utah bituminous coals. With these coals, the

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reliability and availability of the SCR would be seriously jeopardized. The SCR process has therefore not been developed to the point where, if applied to IPP, there is any certainty that it could achieve reliable, continuous reductions in NOx emissions.

2. Thermal DeNOx is an experimental technology on coal and has never been demonstrated to be effective on a coal-fired utility boiler. Therefore,it should not be considered for application at IPP.

3. There is insufficient long-term data to justify retrofit of overfire air ports. The NOx reductions associated with such a retrofit are uncertain, whereas installing overfire air ports could jeopardize the availability and reliability of the boiler as well as the baghouse. The low-NOx burner system incorporated into the present IPP design are capable of yielding low NOx without these adverse side effects.

4. The manufacturer of the IPP boilers incorporates low NOx burners that operate at the minimum practical excess air levels. These burners are proven in use on the type of boiler to be built for IPP. No combustion technology is available for achieving further reductions in excess air without causing unacceptable side effects such as slagging, reduced steam temperature, and loss of fuel efficiency. Further reduction in excess air levels is therefore not practical.

5. Decreased plan heat release through boiler derating has not been consistently demonstrated to yield NOx reductions, and in any case, cannot be considered new technology for the purpose of BACT review.

The Black & Veatch Report demonstrates that even if any of the above technologies could operate reliably and produce significant emission reductions, they would be extremely costly to retrofit at IGS -- either now or some time after plant start-up. For example, as set out in the Black & Veatch

Report, the cost of selective catalytic reduction is estimated to be $1.694 billion (1986 dollars) if retrofitted before commercial operation of IGS and $1.255 billion (in 1986 dollars) if retrofitted at a later time.

The Supplemental KVB Report evaluates the emission data from two operating plants -- Mill Creek and A.B. Brown -- that burn bituminous coal and that have attained emission levels lower than 0.55 pounds per million Btu. The Supplemental KVB Report demonstrates first that there is no valid basis for assuming that the changes in boiler operation discussed in an Exxon report on the Mill Creek data will produce NOx emission levels lower than 0.55 pounds per million Btu at IGS. Second, the Supplemental KVB Report shows that although when Mill Creek operates at fairly low loads it can attain an emission level of less than 0.55 pounds per million Btu, when the Mill Creek unit operates at higher loads, NOx emissions increase. A statistical analysis of the Mill Creek data indicates that if that plant were to operate at close to full load -- as the IGS units will be operated -- it would probably not be able to meet an emission level of less than 0.55. In short the Mill Creek data do not demonstrate that units like the IGS units, which will operate at full load, would be able to meet an emission limit lower than 0.55 pounds per million Btu.

The Supplemental KVB Report also analyzes the data on the A.B. Brown plant. It reveals flaws in the NOx monitors at the plant, decreasing the reliability of the NOx data gathered from those monitors. The report also points out that the A.B. Brown boiler is structurally different from the IGS boilers. The A.B. Brown boiler burns low slagging coal. This permits use of division walls in the A.B. Brown unit, which produces a lower heat release rate in the burner zone, thus generally lowering NOx emisson levels. As the Supplemental KVB Report explains, however, IPP uses high slagging coals which, according to Babcock & Wilcox, preclude the use of division walls in the IGS boilers. In short, the A.B. Brown data are flawed and the A.B. Brown boiler is structurally different from those that are being built at IGS. Thus the A.B. Brown data do not support setting an IGS NOx emission limit lower than 0.55 pounds per million Btu.

IPP's contract with its boiler manufacturer guarantees that the boilers will meet an emission limit of 0.55 pounds per million Btu. The Mill Creek and A. B. Brown data do not provide any basis for concluding that the IGS boilers could meet a NOx limit of 0.50 pounds per million Btu with the current boiler design. Therefore, the imposition of an emission limit below 0.55 would shift liability for compliance from the boiler manufacturer to the IPP. As previously discussed on pages 29 and 30, a new risk of this type could result in substantial additional financing costs. Furthermore,

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the imposition of an emission limit that may be unachievable would require reconsideration of the project's feasibility and could result in cancellation of the IGS unit.

In sum, the current NOx limit of 0.55 pounds per million Btu is achievable and cost-effective. Attempts to install and operate the controls suggested by the DOH could cost up to $1 billion. Furthermore, there is no technical or factual basis for concluding that the IGS boilers, as currently designed, can meet any emission limit lower than 0.55 pounds per million Btu, and imposing any limit lower than 0.55 could jeopardize the financial viability of the project.

c. <u>Response to Comments by Others</u>

Notwithstanding the compatibility of the IGS NOx limits with all air quality requirements of state and federal laws, certain individuals and environmental groups have submitted comments to the DOH expressing concern about the environmental impacts of the IGS NOx emissions. As summarized here and discussed in greater detail in supporting documents, the NOx emissions from IGS will not have any significant adverse environmental impacts; claims to the contrary are without merit.

Several comments suggest that IGS NOx emissions will increase the acidity of precipitation in the geologically sensitive areas of the Wasatch Mountains. These areas of the Wasatch Mountains are 100 miles or more from IGS. In a report prepared by ERT's Dr. George Hidy entitled "Effects of NOx Emissions from the Proposed Intermountain Power Project on

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Deposition and Surface Water Acidification in the Wasatch and Uinta Mountains," Dr. Hidy notes that meteorological conditions and terrain are likely to prevent IGS NOx emissions from ever reaching the sensitive areas of the Wasatch Mountains much less affecting the low alkaline surface waters in the Mountains. However, if such emissions do reach the Mountains, their impacts on the Mountains will be minimal.

Snowpack, precipitation and water quality studies conducted in the Wasatch Mountains and summarized by Dr. Hidy indicate that although the Salt Lake City and Provo metropolitan areas (which are relatively near the Mountains) have grown significantly since the 1950s, there is no evidence that increased NOx emissions from those cities' major mobile and stationary sources have caused any changes in the acidity or nitrate concentrations in the Wasatch Mountains. If such nearby major sources of NOx loadings have no measurable impact, then any increases in current NOx emission levels (in the range of 0.8 percent) due to the far distant IGS cannot be viewed as posing any significant threat of increased acidification. Thus, Dr. Hidy concludes that any small changes in atmospheric levels of NO2 or its derivatives from IGS should have negligible consequences with regard to the pH of low alkalinity surface waters in the geologically sensitive regions of the Wasatch Mountains.

Several other charges and concerns raised by the environmental groups are addressed in a letter from James

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Bowers (of the H. E. Cramer Co.) to IPP's James Anthony. See Attachment 3. For example, the letter responds to a comment charging that no NOx dispersion modeling has been done for IGS. This is not true. As pointed out in the Bowers letter, the H. E. Cramer Company's dispersion model analyses of the IGS have covered NOx emissions and have confirmed the minimal impact of the IGS NOx emissions. Specifically, those analyses show that even under the conservative assumption that all NOx emissions from the plant are converted to NO2, the maximum annual plant impact, which will occur about 7 kilometers from the plant, will be only 4.3 micrograms per cubic meter -- a small percentage of the NO2 health standard of 100 micrograms per cubic meter. Due to these low impacts and due to the fact that IGS and the Wasatch Front are in different air basins, Bowers concludes that IGS NOx emissions impacts on the distant geologically sensitive areas of the Wasatch Mountains will be negligible.

Another set of comments claims that NOx emissions from IGS will somehow exacerbate ozone levels in the ozone nonattainment Salt Lake City area, which is 100 miles from IGS. When EPA issued the PSD permit for the IGS, however, the Agency stated in the permit that IGS NOx emissions would not cause or exacerbate any violation of any national ambient air quality standard. The emissions from IGS are now approximately one-half of those evaluated by EPA. Moreover, Bowers, in his letter to IPP (Attachment 3), concludes that IGS NOx emissions impacts on the distant ozone nonattainment areas will be negligible.

Finally, the commenters make unsubstantiated claims regarding the effects on public health of the NOx emissions of the IGS. IPP believes that those claims are frivolous for two reasons. First, as noted above, the licenses issued by DOH and EPA for the initial IGS design -- with four generating units -- was based on findings that the IGS emissions would not violate the public health standards. Since then, the IPP has decided to build only two generating units, which will emit substantially less total NOx than the four units originally licensed.

Second, a comparison of the available health literature and the ambient NO2 concentrations to which the IGS will contribute shows that the plant will not threaten public health. IGS will be well within the current annual NO2 ambient standard, and there is no basis for concluding that this standard will not limit peak and long-term NO2 concentrations to levels well below those required to protect the public health.[31/] Moreover, modeling analyses of IGS' contribution to short-term NO2 concentrations reveal that no

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31/EPA, "Preliminary Assessment of Health and Welfare Effects Associated with Nitrogen Oxides for Standard Setting Purposes," Draft Staff Paper, e.g. Appendix B (Oct. 1981) ("EPA's NO2 Draft Staff Paper").

NO_2 exposures approaching the levels associated with effects on the public health are produced by IGS.32/

Other claims regarding the effects on visibility of the NOx emissions from the IGS have also been made. As noted above, IPP is going forward with the construction of a facility with total NOx emissions much lower than those initially licensed and found to be acceptable with respect to visibility. Moreover, modeling by H. E. Cramer Company, as reported in the Bowers letter, shows that the plant will not impair the visibility in any class I areas. Finally, as discussed above, IGS will meet BACT emission limits for NOx that are the lowest in the country for a plant burning bituminous coal. Even if emissions could be reduced with the application of additional "retrofit" controls, there is no reason to believe that visibility effects, if any, could be

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32/Based on a highly conservative interpretation of the available health literature, EPA's Staff tentatively concluded that infrequent exposures to 1-hour average NO_2 concentrations evan as high as 566 ug/m3 should "present minimal health risks to children and other sensitive population groups." EPA's Draft Staff Paper at 51 (emphasis added). Modeling analyses show that using the very conservative assumption that 100% of IGS' NOx emissions are NO_2, the maximum one-hour NO_2 concentration caused by IGS is 389 ug/m3, a value well under 566 ug/m^3. More realistic modeling assumptions would produce estimates of peak NO_2 1-hour concentrations between 52 and 61 ug/m3. It should be noted that the above calculations are extremely conservative because they are estimates of maximum one-hour concentrations and EPA's risk estimates contemplated multiple annual exposures. In short, the IGS NOx emissions do not pose any significant risk to public health.

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perceptibly reduced. As EPA explained in publishing regulations for protecting visibility in class I areas, incremental NOx emission reductions "may not be sufficient to achieve any perceptible improvement in visibility."[33]

d. Summary

The current IGS boiler design incorporates the demonstrated and proved NOx control techniques that will meet the permitted NOx limit. The technologies which DOH has asked IPP to evaluate are unproved; as KVB concludes, there is thus no technical or factual basis for concluding that the IGS boilers can meet any emission limit below 0.55 pounds per million Btu. Additionally any changes in the NOx control system will be extremely costly and could jeopardize the financial viability of the project. Finally, the current NOx emission limit adequately protects the public health and welfare. For all these reasons, the current NOx limit -- 0.55 pounds per million Btu on a 30-day average -- is BACT for IGS.

33/45 Fed. Reg. 80087 (col. 1)(1980); EPA, "Guidelines for Determining Best Available Retrofit Technology for Coal-Fired Power Plants and Other Existing Stationary Facilities," Doc. No. EPA-450/3-80-009b at page 13 (Nov. 1980)(incorprated by reference into the visibility rules, 40 C.F.R. § 51.300-307 (1982)). And even these emission reductions were possible only when NSPS was applied to otherwise uncontrolled plants. IGS will be fully controlled.

CONCLUSION

The SO2, particulate matter, and NOx emission limits that IGS is designed to meet represent BACT. No further BACT review is authorized at this time. However, if such a review is conducted, it will show that the current limits are still BACT. The limits for all three pollutants are more stringent than called for by the power plant new source performance standards for coal-fired power plants. In fact, the current standards are among the most stringent in the country.

The current SO2 emission limit requires IGS to achieve a 90 percent reduction in SO2 emissions on a 30 day average and requires IGS to meet a mass emission standard of 0.15 pounds per million Btu. To meet the 90 percent removal standard, IPP has had to purchase a system that approaches the limits of the demonstrated removal capabilities of SO2 scrubbers; IPP has purchased such a state-of-the-art scrubbing system. Achieving any higher removal efficiencies on a long term basis may not be possible; and trying to achieve high reduction levels will cost approximately $1 billion. To meet the 0.15 mass emission limit, IGS has contracted to purchase several sources of low sulfur coal. Imposing a slightly lower mass emission limit on IGS would produce virtually no air quality benefits, but could well result in IPP's having to negotiate new coal contracts, which could cost several hundred million dollars over the life of the plant.

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The current particulate matter standard of 0.02 pounds per million Btu is, we believe, the most stringent in the country. To meet it, IGS has installed a state-of-the-art baghouse system. The current limit is BACT.

The 0.55 pounds per million Btu NOx limit for IGS is also the most stringent in the country for power plants burning bituminous coal. Extensive technical and factual data submitted to the DOH demonstrate that there is no basis for concluding that the IGS boilers can meet an emission limit below 0.55 pounds per million Btu. Not only might a lower limit be unachievable, but also it would be extremely costly even to try to meet a lower limit. For example, the cost of selective catalytic reduction is estimated to be well over $1 billion. Imposing a NOx limit lower than 0.55 pounds per million Btu on the IGS units could thus require IPP to reconsider the feasibility of the entire project.

In summary, the record evidence demonstrates conclusively that the current emission limits for the IGS units are BACT. There is no basis for changing them.

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